B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

BP-14 Final Rate Proposal

Generation Inputs Study Documentation

BP-14-FS-BPA-05A

July 2013

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Table 2.1
Forecast of Installed Generation Capacity for the FY 2014–2015 Balancing Reserve Capacity Quantity Forecast (Values in MW)

		WIND	SOLAR	HYDRO	NON-FEDERAL THERMAL	FEDERAL THERMAL
	A	B	C	D	E	F
1	**Oct-13**	4,520	15	2,529	4,822	1,276
2	**Nov-13**	4,520	15	2,529	4,822	1,276
3	**Dec-13**	4,520	15	2,529	4,822	1,276
4	**Jan-14**	4,520	15	2,529	4,222	1,276
5	**Feb-14**	4,520	15	2,529	4,222	1,276
6	**Mar-14**	4,520	15	2,529	4,222	1,276
7	**Apr-14**	4,520	15	2,529	4,222	1,276
8	**May-14**	4,520	15	2,529	4,222	1,276
9	**Jun-14**	4,520	15	2,529	4,222	1,276
10	**Jul-14**	4,520	15	2,529	4,222	1,276
11	**Aug-14**	4,520	15	2,529	4,222	1,276
12	**Sep-14**	4,520	25	2,529	4,222	1,276
13	**Oct-14**	4,520	25	2,529	4,222	1,276
14	**Nov-14**	4,520	25	2,529	4,222	1,276
15	**Dec-14**	4,520	30	2,529	4,222	1,276
16	**Jan-15**	4,520	30	2,529	4,222	1,276
17	**Feb-15**	4,520	30	2,529	4,222	1,276
18	**Mar-15**	4,520	30	2,529	4,222	1,276
19	**Apr-15**	4,787	30	2,529	4,222	1,276
20	**May-15**	4,787	30	2,529	4,222	1,276
21	**Jun-15**	4,787	30	2,529	4,222	1,276
22	**Jul-15**	4,787	30	2,529	4,222	1,276
23	**Aug-15**	4,787	30	2,529	4,222	1,276
24	**Sep-15**	4,787	30	2,529	4,222	1,276
25	**BP-14 AVG**	**4,587**	**23**	**2,529**	**4,297**	**1,276**

Table 2.2 Total Balancing Reserve Capacity Requirement (99.5%) with April 2013 Elections (Values in MW)									
		INSTALLED CAPACITY (MW)						TOTAL BALANCING RESERVE CAPACITY NEED (MW)	
		ALL WIND	Participation in CSGI*	Participation in 30/15**	Participation in 30/30***	Participation in 30/60****	Un-Committed*****	INC	DEC
	A	B	C	D	E	D	E	L	M
1	Oct-13	4,520	1,391	0	25	1,000	2,104	939	-1,124
2	Nov-13	4,520	1,391	0	25	1,000	2,104	939	-1,124
3	Dec-13	4,520	1,391	0	25	1,000	2,104	939	-1,124
4	Jan-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
5	Feb-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
6	Mar-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
7	Apr-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
8	May-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
9	Jun-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
10	Jul-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
11	Aug-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
12	Sep-14	4,520	1,391	0	25	1,000	2,104	941	-1,125
13	Oct-14	4,520	1,391	25	0	1,000	2,104	943	-1,127
14	Nov-14	4,520	1,391	25	0	1,000	2,104	943	-1,127
15	Dec-14	4,520	1,391	25	0	1,000	2,104	943	-1,127
16	Jan-15	4,520	1,391	25	0	1,000	2,104	943	-1,127
17	Feb-15	4,520	1,391	25	0	1,000	2,104	943	-1,127
18	Mar-15	4,520	1,391	25	0	1,000	2,104	943	-1,127
19	Apr-15	4,787	1,391	25	0	1,267	2,104	953	-1,140
20	May-15	4,787	1,391	25	0	1,267	2,104	953	-1,140
21	Jun-15	4,787	1,391	25	0	1,267	2,104	953	-1,140
22	Jul-15	4,787	1,391	25	0	1,267	2,104	953	-1,140
23	Aug-15	4,787	1,391	25	0	1,267	2,104	953	-1,140
24	Sep-15	4,787	1,391	25	0	1,267	2,104	953	-1,140
25	**BP-14 AVG**	**4,587**	**1,391**	**13**	**13**	**1,067**	**2,104**	**945**	**-1,129**

NOTES:
* Participation in Customer Supplied Generation Imbalance or self-supply of the generation imbalance portion of VERBS
** Participation in 30/15 means committing to schedule using 30-minute persistence on a 15-minute basis
*** Participation in 30/30 means committing to schedule using 30-minute persistence on a 30-minute basis
**** Participation in 30/60 means committing to schedule using 30-minute persistence on a 60-minute basis
***** Uncommitted means reserves will be held assuming schedules at 45-minute persistence on a 60-minute basis

Table 3.1
Calculation of Total Balancing Authority Reserve Obligation
Proposed WECC Operating Reserve Standard BAL-002-WECC-1

	A	B	C	D	E	F
	Fiscal Year	**BPA Area Load (MW)**	**Total System Generation (MW)**	**3% BA Load (MW)**	**3% BA Generation (MW)**	**Total BPA BAA Reserve Obligation (MW)**
1	2005	5,291	11,522			
2	2006	5,444	12,210			
3	2007	5,753	11,859			
4	2008	6,429	12,594			
5	2009	6,100	11,847			
6	2010	5,944	11,624			
7	2011	6,223	13,140			
8	2012 Forecast	6,189	12,776			
9	2013 Forecast	6,243	12,855			
10	2014 Forecast	6,222	12,449	187	373	560.1
11	2015 Forecast	6,354	12,594	191	378	568.5
12	**FY 2014-2015 Average**	**6,288**	**12,980**			**564.3**

BPA area load from RODS (account 242200) from FY 2005 through June FY 2012. July FY 2012 through FY 2015 is forecast of BPA area load provided by BPA Agency Load forecast.

BPA total system generation (account 202100) from FY 2005 through June FY 2012. The forecast BPA system generation is based on a historical three year average (FY 2010 - 2012) of BPA generation to BPA load ratio of 2.06:1, and adjusted for two non-federal thermal generators leaving the BPA balancing authority during the rate period.

	A	B	C	D
Table 3.2 Total BPA Balancing Authority Area Reserve Obligation Proposed WECC Operating Reserve Standard BAL-002-WECC-1				
		Total BPA BAA Reserve Obligation (MW)	**Total Third-Party Supply/ Self-Supply Reserve Obligation (MW)**	**Total BPA BAA Reserve Obligation Provided by BPA PS (MW)**
1	FY 2014	560.1	108.5	451.6
2	FY 2015	568.5	108.5	460.0
3	**Annual Average of FY 2014-2015**	**564.3**	**108.5**	**455.8**

Column C: Total Third Party and Self-Supply is based on customer election effective May 1, 2013, and adjusted for historical usage.

Column D: BPA Power Services share of the Reserve Obligation is Column B minus Column C.

Table 3.3
Balancing Authority Reserve Obligation Provided by BPA PS by Month

	A	B	C	D
		FY 2014 (MW)	**FY 2015 (MW)**	**FY 2014-2015 Average**
1	Oct	398.0	389.1	393.6
2	Nov	423.2	418.2	420.7
3	Dec	470.6	473.6	472.1
4	Jan	485.5	498.9	492.2
5	Feb	470.4	483.2	476.8
6	Mar	452.3	464.7	458.5
7	Apr	453.0	465.2	459.1
8	May	478.6	490.8	484.7
9	Jun	511.0	524.1	517.6
10	Jul	472.4	485.0	478.7
11	Aug	426.3	437.9	432.1
12	Sep	378.2	388.8	383.5
13	**FY Average**	**451.6**	**460.0**	**455.8**

Assumes BAL-002-WECC-1 is effective for the entire FY 2014-2015 rate period.

Table 4.1 Synchronous Condenser Projected Motoring Hours, Hourly Energy Consumption and Energy Costs										
	A	B	C	D	E	F	G	H	I	J
	Generating Project	**Nameplate rating (MW/unit)**	**Motoring power consumption (MW/unit)**	**Projected Units to be used**	**Condensing Hours FY 2007**	**Condensing Hours FY 2008**	**Condensing Hours FY 2009**	**Average Annual Condensing hours/year [(E+F+G)/3]**	**Energy Consumption MWhrs/year [H * C]**	**Total Cost of Energy [I * Market Price Forecast of energy]**
1	**John Day, units 11-14**	155	3.0	units 11-14	2,697	4,005	4,127	3,610	10,829	$ 312,417
2	**The Dalles, units 15-20**	99	1.5	units 15-20	3,006	2433	3,085	2,841	4,262	$ 122,959
3								**SUBTOTAL - SOUTHERN INTERTIE***	**15,091**	**$ 435,375**
4	**Grand Coulee, units 19-24**	690 (units 19-21) 805 (units 22-24)	11.0	units 19-21	2,240	2,848	2,376	2,488	27,368	$ 789,567
5	**Dworshak (small units)**	103	4.0	units 1-2	25	6	10	14	55	$ 1,577
6	**Dworshak (big unit)**	259	8.0	unit 3	154	15	142	104	829	$ 23,926
7	**Palisades, units 1-4**	44	0.6	units 1-4	2320	1,773	1,177	1,757	1,054	$ 30,408
8	**Detroit, units 1-2**	58	2.0	units 1-2	NA	NA	NA	0	0	$ -
9	**Green Peter, units 1-2**	46	1.2	units 1-2	NA	NA	NA	0	0	$ -
10	**Lookout Point, units 1-3**	46	1.1	units 1-3	NA	NA	NA	0	0	$ -
11	**Hungry Horse, units 1-4**	107	2.5	units 1-4	0	0	0	0	0	$ -
12								**SUBTOTAL - NETWORK***	**29,306**	**$ 845,478**
13								**TOTAL ENERGY COST**	**44,397**	**$ 1,280,853**
14	**Market Price Forecast of energy ($/MWh)**	**$ 28.85**								

***Synchronous condensing costs for the John Day and The Dalles projects are allocated to the Southern Intertie segment. Costs of all other projects are allocated to the Network segment.**

Table 4.2 **Determination of Synchronous Condenser Plant Modification Costs*** **($ thousands)**				
	A	B	C	D
		FY 2014	**FY 2015**	**Annual Average of FY 2014–2015**
1	**Synchronous Condensers Net Plant**	6,216	6,113	6,165
2	Total Corps/Reclamation Average Net Plant	6,124,428	6,351,414	6,237,921
3	**percent**	0.10%	0.10%	0.10%
4	Corps/Reclamation Net Interest	182,054	191,514	186,784
5	**Sync Cond Net Interest**	185	184	185
6	Corps/Reclamation MRNR	-	0	0
7	**Sync Cond MRNR**	-	-	-
8	**Sync Cond Depreciation**	103	103	103
9	**Total Sync Cond Plant Modification Costs**	288	287	288

* These are costs for plant modifications at John Day and The Dalles to enable synchronous condenser operation. These costs are allocated to the Southern Intertie segment.

Table 4.3 **Summary of Synchronous Condenser Costs** **($ thousands)**				
	A	B	C	D
		FY 2014	**FY 2015**	**Annual Average of FY 2014–2015**
1	Modifications at John Day and The Dalles*	$ 288	$ 287	$ 288
2	**Energy Consumption - John Day and The Dalles**	$ 435	$ 435	$ 435
3	**Subtotal - Southern Intertie**	**$ 723**	**$ 722**	**$ 723**
4	**Energy Consumption - Network**	$ 845	$ 845	$ 845
5	**Total Synchronous Condenser Costs**	**$ 1,569**	**$ 1,568**	**$ 1,568**

* These are costs for plant modifications at John Day and The Dalles to enable synchronous condenser operation. These costs are allocated to the Southern Intertie segment.

Table 5.1
Estimated Costs of Generation Drop of Unit 22, 23, or 24 at the Grand Coulee Third Powerhouse

	Equipment	Incremental Equipment Deterioration, Replacement or Overhaul Costs			Incremental Routine Operation and Maintenance Costs			Incremental Lost Revenue In The Event of Replacement or Overhaul				Total Cost Per Drop
		% Life Reduction Per Drop	Cost of Major Overhaul (1)	Cost/Drop	% Increase O&M Per Drop	Annual O&M Cost	Cost/Drop	Probability of Failure	Months of Downtime	Downtime Cost (2)	Cost/Drop	
	A	B	C	D	E	F	G	H	I	J	K	L
1	550kV Circuit Breaker (50% of replacement)	0.04%	$ 730,000	$ 292	0.04%	$ 4,941	$ 2	0.04%	1	$ 1,386,531	$ 555	**$ 849**
2	Main Power Transformer (equal to replacement)	0.015%	$ 8,332,074	$ 1,250	0.015%	$ 57,069	$ 9	0.018%	1	$ 1,386,531	$ 250	**$ 1,508**
3	Generator (rewinding)	0.71%	$ 18,542,000	$ 131,648	0.71%	$ 450,000	$ 3,195	0.71%	18	$ 24,957,558	$ 177,199	**$ 312,042**
4	Turbine (refurbished)	0.24%	$ 1,460,000	$ 3,504	0.24%	$ 450,000	$ 1,080	0.05%	16	$ 22,184,496	$ 11,092	**$ 15,676**
5	500 kV Cable (replacement)	0.055%	$ 3,762,000	$ 2,069	0.055%	$ 281,779	$ 155	0.055%	1	$ 1,386,531	$ 763	**$ 2,987**
6	**Total Cost Per Drop**			**$ 138,763**			**$ 4,441**				**$ 189,858**	**$ 333,061**

(1) Updated to FY 2014-2015 from original Harza Engineering Company study using the Handy-Whitman Index to calculate cost multiplier 1.46.

(2) The downtime cost from last unit out at Coulee analysis, assumes normal unit availability at Coulee and then the loss of an additional big unit. The current value of availability is adjusted to forecasted cost of energy during the FY 2014-2015 rate period. This analysis includes a planned overhaul of one big unit at Grand Coulee starting in 2013.

Table 6.1
Discretionary Redispatch Under Attachment M of BPA's Open Access Transmission Tariff (OATT)
October 2009 through September 2011

	A	B	C	D	E	F	G	H	I
	Location	**Amount Requested (MWh or MW)***	**Amount Delivered (MWh)**	**Total Cost**	**$/MWh**	**Duration of Redispatch Event (Hours)****	**Units Incremented**	**Units Decremented**	**Cause**
1	**North of Hanford Flow Gate:**								
2	1/18/2011	150	80	$ 800	$ 10.00	0.6	CHJ	LWG, LGS	Flows exceed Maximum System Operating Level
3	8/25/2011	100	33	$ 567	$ 17.18	0.5	JDA	CHJ	Flow gate flows over System Operating Limit
4	**North of John Day Flow Gate:**								
5	6/21/2010	133	133	$ 1,333	$ 10.00	2	JDA	GCL	Path 73 over SOL
6	9/27/2010	458	458	$ 11,458	$ 25.00	5	GCL	TDA	
7	7/1/2011	100	27	$ 133	$ 4.93	0.4	JDA, TDA	CHJ	Flows exceed System Operating Level
8	7/1/2011	100	43	$ 217	$ 5.05	0.6	JDA, TDA	CHJ	Flows exceed System Operating Level
9	7/1/2011	100	27	$ 133	$ 4.93	0.4	JDA, TDA	CHJ	Flows exceed System Operating Level
10	**North of John Day/Raver Paul Flowgates:**								
11	7/2/2011	50	17	$ 417	$ 24.53	0.5	JDA	CHJ	Flows exceed System Operating Level
12	7/2/2011	50	10	$ 250	$ 25.00	0.4	JDA	CHJ	Flows exceed System Operating Level
13	**Ice Harbor Area:**								
14	10/13/2009	20	12	$ 308	$ 25.67	1	IHR	GCL	Overloading of Franklin Bank #4
15	**Cross Cascades North Flow Gate:**								
16	5/18/2010	459	343	$ 4,465	$ 13.00	2	MCN, JDA, TDA	GCL	Cross Cascades North over SOL
17	5/19/2010	1368	1368	$ 13,683	$ 10.00	8	MCN, JDA, TDA	GCL	Cross Cascades North over SOL
18	**South of Allston Flow Gate:**								
19	3/18/2011	150	119	$ 4,050	$ 34.03	1.6	CHJ	TDA	South of Allston South to North System Operating Level Exceeded
20	3/20/2011	304	127	$ 4,053	$ 31.91	0.8	GCL,CHJ	JDA,TDA,BON	South of Allston South to North System Operating Level Exceeded
21	3/20/2011	105	27	$ 735	$ 27.22	0.5	GCL, CHJ	TDA, BON	South of Allston South to North System Operating Level Exceeded
22	**Paul-Allston Flow Gate:**								
23	4/18/2010	793	793	$ 7,917	$ 9.98	2	MCN, JDA,TDA, BON	GCL	
24	4/19/2010	244	244	$ 2,442	$ 10.00	2	MCN, JDA, TDA	GCL	
25	**McNary Area:**								
26	4/5/2010	483	483	$ 4,833	$ 10.01	5	MCN	GCL	
27									
28	**FY 2010 Total:**			$ 46,439					
29	**FY 2011 Total:**			$ 11,355					
30	**Discretionary Redispatch Total:**			$ 57,794					

*Units are MWh for 2010 and MW for 2011.
**For 2010, duration is rounded to the nearest whole hour.

Table 6.2:
NT Firm Redispatch Under Attachment M of BPA's OATT Resulting from the Purchase of Energy or Transmission for Planned and Unplanned Outages October 2009 through September 2011

		A	B	C	D
		MWh	**Cost**	**$/MWh**	**Constrained Path(s)/Cause**
1	Oct-09	716	$ 1,202	$ 1.68	LaGrande Outage
2	Nov-09	-			
3	Dec-09	330	$ 1,765	$ 5.35	BPA network stranded load
4	Jan-10	-			
5	Feb-10	4,240	$ 14,546	$ 3.43	LaGrande Outage/Malin-Hilltop outage
6	Mar-10	572	$ 364	$ 0.64	LaGrande Outage
7	Apr-10	-			
8	May-10	5,204	$ 15,030	$ 2.89	Malin-Hilltop outage/Stranded Load/Vera Outage
9	Jun-10	7	$ 40	$ 5.71	LaGrande Outage
10	Jul-10	305	$ 7,653	$ 25.09	Backup Svc Sched Outage
11	Aug-10	1,501	$ 8,661	$ 5.77	LaGrande Outage
12	Sep-10	-			
13	Oct-10	912	$ 11,353	$ 12.45	LaGrande Outage
14	Nov-10	141,004	$ 414,655	$ 2.94	LaGrande/VERA Outage
15	Dec-10	-			
16	Jan-11	648	$ 3,165	$ 4.89	RATS
17	Feb-11	92	$ 320	$ 3.48	COI outage in Cali. prevented deliveries to RATS
18	Mar-11	479	$ 1,904	$ 3.97	LaGrande
19	Apr-11	1,627	$ 4,874	$ 3.00	LaGrande and Hamey
20	May-11	4,478	$ 28,038	$ 6.26	LaGrande and Kalispell-Elmo
21	Jun-11	-			
22	Jul-11	555	$ 3,202	$ 5.77	LaGrande
23	Aug-11	518	$ 2,989	$ 5.77	LaGrande
24	Sep-11	-			
25	**Total**	**163,188**	**$ 519,761**		
26	**FY 2010 Total**	**12,875**	**$ 49,261**		
27	**FY 2011 Total**	**150,313**	**$ 470,500**		

Table 7.1
COE Transmission Segmentation as of 9/30/2011
Bonneville Dam

	A	B	C	D	E
1	**Prop ID 1/**	**Plant Item**	**Book Cost**	**Generation Integration**	**Integrated Network**
2	BONNE-13361	Power transformers	$28,239,329	28,239,329	0
3	BONNE-13358	Switchyard circuit breaker 2/	1,499,685	599,874	899,811
4	BONNE-13559	Switchyard circuit breaker 2/	1,499,961	599,984	899,976
5	BONNE-13360	Switchyard circuit breaker 2/	1,500,514	600,206	900,308
6		**Total:**	**$32,739,488**	**30,039,393**	**2,700,096**
7	**Notes:**				
8	1/ Investment from Corps of Engineers records				
9	2/ (6 each) 115 kV PCBs; supporting 2 Generation Integration terminals, and 3 Network terminals.				
10	Total PCB cost allocated 2/5 to GI and 3/5 to Network.				

Table 7.2
Columbia Basin (Grand Coulee) Cost Summary

	A	B	C
1		**As of 9/30/2011**	
2	**Segment**	**Investment**	**Percent**
3	**TOTAL TRANSMISSION**		
4	Network	71,345,014	31.13%
5	Generation Integration	155,382,130	67.80%
6	Delivery	2,449,904	1.07%
7	**Total**	**229,177,047**	**100.00%**
8	**THIRD POWERHOUSE (500 kV Facilities)**		
9	Network	43,686,672	28.60%
10	Generation Integration	109,041,548	71.40%
11	**Total**	**152,728,220**	**100.00%**
12	**FIRST & SECOND POWERHOUSE & OTHERS**		
13	Network	27,658,342	36.18%
14	Generation Integration	46,340,581	60.62%
15	Delivery	2,449,904	3.20%
16	**Total**	**76,448,827**	**100.00%**
17	Investment includes Interest During Construction (IDC).		

Table 7.3
Columbia Basin Costs (Grand Coulee)
Bureau of Reclamation data for investments (in $) as of 9/30/2011

	A	B	C	D	E	F
1				Segment		
2		Value	Integrated Network	Generation Integration	Utility Delivery	Source
3	**Total Electric Plant 1/**	1,284,454,226				USBR Schedule 1, page 10
4	Interest During Construction (IDC)	133,829,807				USBR Schedule 1, page 10
5	Ratio of IDC to total plant	11.6%				
6	**13.031 Pump Generator Switchyard**	4,742,053				USBR Schedule 1, page 10
7	Add: Interest During Construction	551,551				Applied IDC ratio
8	Subtotal times percent allocation 2/	5,293,605	0.0%	100.0%	0.0%	All Generation Integration
9	Equals: Amount Allocated		0	5,293,605	0	
10	**13.034 500kV & Other Switchyard**	136,575,003				USBR Schedule 1, page 10
11	Add: 500 kV Switchyard Roof Replacement	176,899				USBR Schedule 1, page 4
12	Add: 500 kV & Other Switchyard Land	70,623	0.03%			USBR Schedule 1, page 4
13	Less: Reactive Equipment 3/	(7,181,279)				USBR records
14	Less: 500kV cables 4/	(22,789,063)				USBR records
15	Subtotal and percent allocation 5/	106,852,183	29.9%	70.1%	0.0%	Table 8.4
16	Equals: Amount Allocated		31,955,793	74,896,390	0	
17	Add back: Reactive (Network); Cables (GI)		7,181,279	22,789,063	0	Lines 13 & 14
18	Subtotal		39,137,072	97,685,453	0	
19	Add: Interest During Construction 6/		4,549,599	11,356,095	0	Applied IDC ratio
20	Equals: Amount Allocated		43,686,672	109,041,548	0	
20	**13.035 Modified Left Switchyard**	60,775,966				4/ USBR Schedule 1, page 10
21	Less: Lines 4/	(7,199,787)				USBR records
22	Subtotal and percent allocation 7/	56,541,633	43.8%	52.3%	3.9%	Table 8.4
23	Equals: Amount Allocated		24,776,565	29,570,425	2,194,643	
25	Add back: Lines (all GI)		0	7,199,787	0	Line 21
26	Subtotal		24,776,565	36,770,212	2,194,643	
27	Add: Interest During Construction		2,881,777	4,276,765	255,260	Applied IDC ratio
28	Equals: Amount Allocated		27,658,342	41,046,977	2,449,904	
30	**Total allocation by segment**		**71,345,014**	**155,382,130**	**2,449,904**	
31	Percentage allocation		31.1%	67.8%	1.1%	
32	**NOTES:**					
33	1/ Assume all transmission costs to be segmented are included in the USBR Schedule 1 for the Columbia Basin (Grand Coulee) project.					
34	2/ Pump generator switchyard and power plant all allocated to Generation Integration; average IDC included.					
35	3/ Assume (a) Job 1990000 Misc Equipment refers to the Reactive Equipment costs and (b) Reactive equipment is all Network					
36	4/ Assume (a) cables, Job 1840000 and 1850000, are all underground feeds and (b) these cables are part of Generation Integration.					
37	5/ All 500 kV line and substation costs, plus Roof Replacement costs and Land, less direct assigned cables; 6 of 12 terminals to Power House.					
38	6/ Reclamation does not accrue IDC on Electric Land in Service. These calculations therefore do not apply IDC on Land investments.					
39	7/ Assume this includes all 230 kV, 115 kV, and low voltage equipment, less direct assigned cables; IDC not included.					

Table 7.4
Grand Coulee Networking Investment Ratio-Assignment
Based on BPA Typical Costs of Facilities 1/

	A	B	C	D	E	F
1	Items	Integrated Network	Generation Integration	Utility Delivery	Total	Typical Cost 1/
2	**500 kV Switchyard items**					
3	500 kV terminal	6	6	0	12	
4	Step-ups 7-800 MVA	0	6	0	6	
5	Reactive Equipment	1	0	0	1	
6	**Allocated Costs ($000)**					
7	500 kV terminal	27,000	27,000	0	54,000	4,500
8	Step-ups 7-800 MVA	0	48,000	0	48,000	8,000
9	Reactive Equipment	5,000	0	0	5,000	5,000
10	**Total**	**32,000**	**75,000**	**0**	**107,000**	
11	Percent Allocation	29.9%	70.1%	0.0%	100.0%	
12	**Left Switchyard (includes 230kV, 115kV & 12kV yards) items**					
13	230 kV PCB	17	5	0	22	
14	500/230 tx 1200MVA	1	0	0	1	
15	230/287kV tx	1	0	0	1	
16	230/115 tx 230MVA	1	0	0	1	
17	115kV PCB	5	2	2	9	
19	12kV PCB 2/	0	24	6	30	
18	Delivery - 20 MVA tx	0	3.2	0.8	4	
20	Step-ups 1-125MVA	0	18	0	18	
21	**Allocated Costs ($000)**					
22	230 kV PCB	9,520	2,800	0	12,320	560
23	500/230 tx 1200MVA	9,800	0	0	9,800	9,800
24	230/287kV tx	2,600	0	0	2,600	2,600
25	230/115 tx 230MVA	2,600	0	0	2,600	2,600
26	115kV PCB	1,875	750	750	3,375	375
28	12kV PCB	0	3,120	780	3,900	130
27	Delivery - 20 MVA tx	0	3,232	808	4,040	1,010
29	Step-ups 1-125MVA	0	21,600	0	21,600	1,200
30	**Total**	**26,395**	**31,502**	**2,338**	**60,235**	
31	Percent Allocation	43.8%	52.3%	3.9%	100.0%	
32						
33	1/ Typical average unit costs are from 1998 Segmentation Study.					
34	2/ 16 each PCBs in 11.95 kV yard, assume only 6 used to serve Delivery. Rest are assumed to serve USBR.					

Table 7.5
USBR Segmentation – Other Projects
As of 9/30/2011 – Based on data from USBR

	A	B	C	D	E
	PROJECT	**TRANSMISSION INVESTMENT 1/**	**INTEGRATED NETWORK**	**GENERATION INTEGRATION**	**LAND IN SERVICE /2**
1	Hungry Horse (see below)	9,662,518	2,019,034	7,643,485	
2	Boise 3/	1,844,220	0	1,844,220	2,928
3	Yakima 4/	3,353,824	0	3,353,824	7,216
4	Green Springs 5/	178,988	0	178,988	
5	Minidoka (see below)	1,700,557	925,653	774,904	314
6	Palisades (see below)	2,197,305	467,733	1,729,572	
7	**Total**	**18,937,411**	**3,412,419**	**15,524,992**	**10,458**
8	Total less Land	**18,926,953**			
9	**SEGMENT PERCENTAGES FOR MULTI-SEGMENT PLANTS**				
10	Item	Cost 6/	Network	Gen Int	Total
11	**Hungry Horse** 7/				
12	230kV PCBs (4 each)	560,000	1,120,000	1,120,000	2,240,000
13	180MVA step-ups (2 each)	1,560,000	0	3,120,000	3,120,000
14			1,120,000	4,240,000	5,360,000
15	*Percent of total*		20.9%	79.1%	100.0%
16	**Minidoka** 8/				
17	138kV PCBs (7 each)	375,000	1,750,000	875,000	2,625,000
18	Step-up to 138kV	590,000	0	590,000	590,000
19	*Total*		1,750,000	1,465,000	3,215,000
20	*Percent of total*		54.4%	45.6%	100.0%
21	**Palisades** 9/				
22	115kV PCBs (9 each)	375,000	1,446,429	1,928,571	3,375,000
23	35MVA step-ups (4 each)	590,000	0	2,360,000	2,360,000
24	10MVA 115/12.5kV 10/	1,060,000	0	1,060,000	1,060,000
25	*Total*		1,446,429	5,348,571	6,795,000
26	*Percent of total*		21.3%	78.7%	100.0%
27	**NOTES:**				
28	1/ Data from Bureau of Reclamation Transmission Plant In Service details (incl. IDC allocation)				
29	2/ Land in service is subset of total Transmission Investment; Land specifically for transmission facilities				
30	3/ Includes Anderson Ranch and Black Canyon				
31	4/ Includes the Roza and Kennewick divisions				
32	5/ does not include Construction in Progress				
33	6/ Typical average unit costs are from 1998 segmentation study				
34	7/ Hungry Horse: 2 GI & 2 Network terminals with 4 breakers; step-up transformers uses 230/69kV 75 MVA cost				
35	8/ Minidoka: 2 GI & 4 Network terminals with 7 breakers; step-up xfmr uses 115/34.5kV 25 MVA cost				
36	9/ Palisades: 4 GI & 3 Network terminals with 9 breakers; 4 step-up transformers use 115/34.5kV 25 MVA cost				
37	10/ Palisades 12.5kV - Lower Valley provides station service to USBR - no delivery feed to Lower Valley				

Table 7.6
Segmentation Summary – All COE and Reclamation Projects

	A	B	C	D
		Generation Integration	**Integrated Network**	**Utility Delivery**
1	**Reclamation Projects:**			
2	Columbia Basin (Grand Coulee) Project	155,382,130	71,345,014	2,449,904
3	Other Projects	15,524,992	3,412,419	0
4	**Total Reclamation Projects**	**170,907,122**	**74,757,433**	**2,449,904**
5	**COE Projects:**			
6	**Total COE (Bonneville) Project**	**30,039,393**	**2,700,096**	**0**
7	**TOTAL ALL PROJECTS:**	**200,946,514**	**77,457,529**	**2,449,904**
8	**TOTAL TRANSMISSION ALLOCATION:**	**79,907,432**	(Network plus Utility Delivery)	

Table 8.1
Load Factor Calculation for Station Service Energy Use Analysis

	Substation Name	Installed Transformation (kVA)	Historical Average Monthly Use (kWh)	Calculated Load Factor
	A	B	C	D
1	**Large**			
2	Alvey	2,267	96,923	
3	Bell	2,250	149,000	
4	Snohomish	1,250	78,000	
5	Olympia	1,100	132,738	
6	Covington	946	108,333	
7	Pearl	875	28,067	
8	Longview	825	38,317	
9	McNary	800	108,717	
10	Chemawa	725	18,140	
11	Anaconda	600	42,910	
12	Columbia	600	18,292	
13	John Day	500	65,896	
14	Santiam	400	25,740	
15	St. Johns	310	15,858	
16	Port Angeles	300	49,920	
17	Valhalla	300	17,592	
18	Fairview	300	12,560	
19	**Subtotal**	14,348	1,007,003	
20	**Medium**			
21	Oregon City	225	13,663	
22	Walla Walla	150	6,919	
23	LaGrande	150	5,663	
24	Ellensburg	100	3,897	
25	Roundup	75	5,708	
26	Boardman	75	1,595	
27	Drain	65	1,654	
28	Reedsport	55	3,922	
29	**Subtotal**	895	43,021	
30	**Small**			
31	Sappho	45	2,363	
32	Lookout Point	40	3,387	
33	The Dalles	38	2,657	
34	Bandon	25	1,746	
35	Gardiner	25	1,402	
36	Creston	15	1,122	
37	Hauser	10	1,525	
38	Duckabush	10	1,192	
39	Ione	5	1,028	
40	**Subtotal**	213	16,422	
41	**TOTAL**	**15,456**	**1,066,446**	**9.45%**

Load factor calculation is the Historical Average Monthly Use divided by Installed Transformation divided by 730 average hours in the month.
D = C / B / 730.

Table 8.2
Calculation of Station Service Use and Cost

	Facility Type	Installed Transformation (kVA)	Average Monthly Use[1] (kWh)	Annual Station Service Use[2] (kWh)	Annual Average Market Price Forecast ($/MWh)	Cost Allocation for Station Service per Year[3] ($)
	A	B	D	E	F	G
1	Large	40,128	2,768,230			
2	Medium	4,673	322,367			
3	Small	1,413	97,476			
4	Big Eddy/Celilo Complex		1,822,937			
5	Ross Complex		1,749,300			
6	**Total**	**46,214**	**6,760,310**	**82,665,068**	**$ 28.85**	**$ 2,384,885**

1/ For Large, Medium and Small substations, the calculated average monthly use is installed transformation times 9.45% average calculated load factor times 730 average hours in month (D = B * 9.45% * 730). Historical usage is metered for Big Eddy/Celilo and Ross Complexes.

2/ Annual Station Service Use is the monthly use times 12 months plus BPA Transmission Network Losses (1.9%, or 1,541,351 kWh).

3/ Cost Allocation for Station Service per Year is the amount of Station Service Energy Forecasted per Year times the Annual Average Market Price Forecast (G = E * F)

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